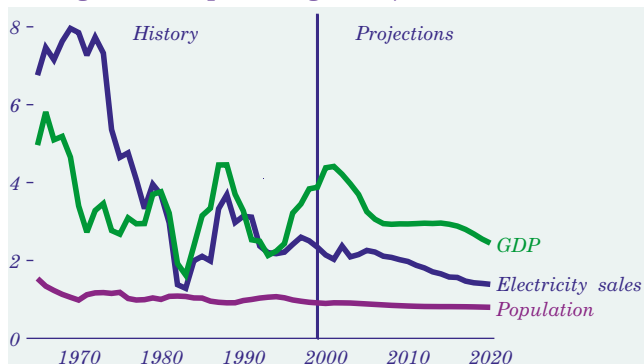


## Electricity Sales

### Electricity Use Is Expected To Grow More Slowly Than GDP

**Figure 70. Population, gross domestic product, and electricity sales, 1965-2020 (5-year moving average annual percent growth)**



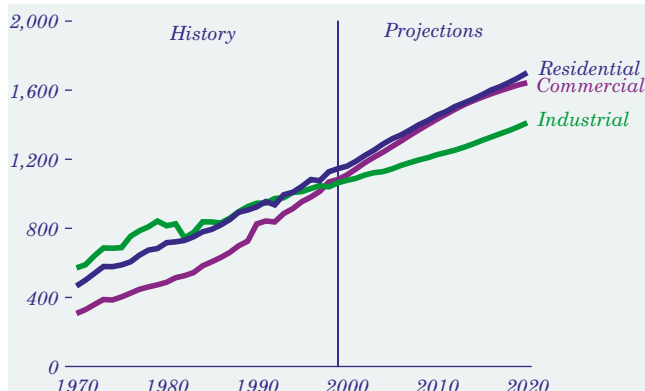
As generators and cogenerators try to adjust to the evolving structure of the electricity market, they also face slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. That positive relationship is expected to continue, but the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent per year, nearly twice the rate of economic growth (Figure 70). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is dampened by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. The continuing saturation of electricity appliances, the availability and adoption of more efficient equipment, and efficiency standards are expected to hold the growth in electricity sales to an average of 1.8 percent per year between 1999 and 2020, compared with 3.0-percent annual growth in GDP.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than currently expected, they could offset future efficiency gains to some extent.

### Continued Growth in Electricity Use Is Expected in All Sectors

**Figure 71. Annual electricity sales by sector, 1970-2020 (billion kilowatthours)**



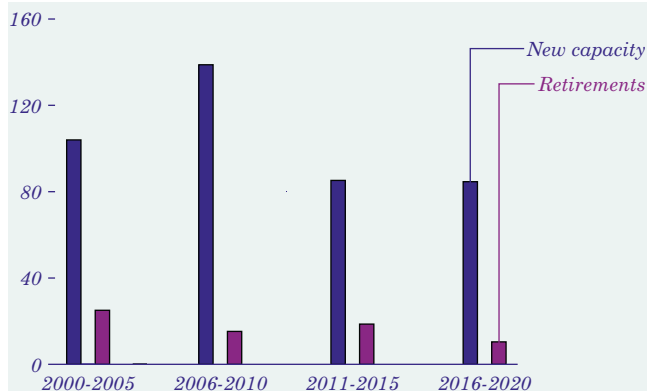
With the number of U.S. households projected to rise by 1.0 percent per year between 1999 and 2020, residential demand for electricity is expected to grow by 1.9 percent annually (Figure 71). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks in the late afternoon and evening, when household cooling and lighting needs are highest. This periodicity increases the peak-to-average load ratio for local utilities, which rely on quick-starting gas turbines or internal combustion engines to satisfy peak demand. Although many regions currently have surplus baseload capacity, strong growth in the residential sector is expected to result in a need for more “peaking” capacity. Between 1999 and 2020, generating capacity from gas turbines and internal combustion engines is projected to increase from 75 gigawatts to 211 gigawatts.

Electricity demand in the commercial and industrial sectors is projected to grow by 2.0 and 1.4 percent per year, respectively, between 1999 and 2020. Projected growth in commercial floorspace of 1.3 percent per year and growth in industrial output of 2.6 percent per year contribute to the expected increase.

In addition to sectoral sales, cogenerators in 1999 produced 156 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, cogenerators are expected to see only a slight decline in their share of total generation, increasing their own-use generation to 227 billion kilowatt-hours as the demand for manufactured products increases.

## Retirements and Rising Demand Are Expected To Require New Capacity

**Figure 72. Projected new generating capacity and retirements, 2000-2020 (gigawatts)**



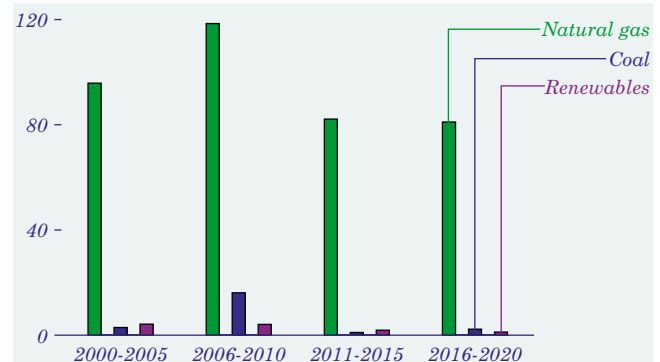
Although growth in electricity demand from 1999 to 2020 is projected to be slower than in the past, 393 gigawatts of new generating capacity (excluding cogenerators) is expected to be needed by 2020 to meet growing demand and to replace retiring units. Between 1999 and 2020, 26 gigawatts (27 percent) of current nuclear capacity and 43 gigawatts (8 percent) of current fossil-fueled capacity [85] are expected to be retired. Of the 162 gigawatts of new capacity expected after 2010 (Figure 72), 16 percent will replace retired nuclear capacity.

The projected reduction in baseload nuclear capacity has a modest impact on the electricity outlook after 2010: 51 percent of the new combined-cycle and 15 percent of the new coal-fired capacity projected in the entire forecast are expected to be brought on line between 2010 and 2020. Before the advent of natural gas combined-cycle plants, fossil-fired baseload capacity additions were limited primarily to pulverized-coal steam units; however, efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared with 49 percent for coal-steam units, and the expected construction costs for combined-cycle units are only about 41 percent of those for coal-steam plants.

As older nuclear power plants age and their operating costs rise, 27 percent of currently operating nuclear capacity is expected to be retired by 2020. More optimistic assumptions about operating lives and costs for nuclear units would reduce the projected need for new fossil-based capacity and reduce fossil fuel prices.

## About 1,300 New Power Plants Could Be Needed by 2020

**Figure 73. Projected electricity generation capacity additions by fuel type, including cogeneration, 2000-2020 (gigawatts)**



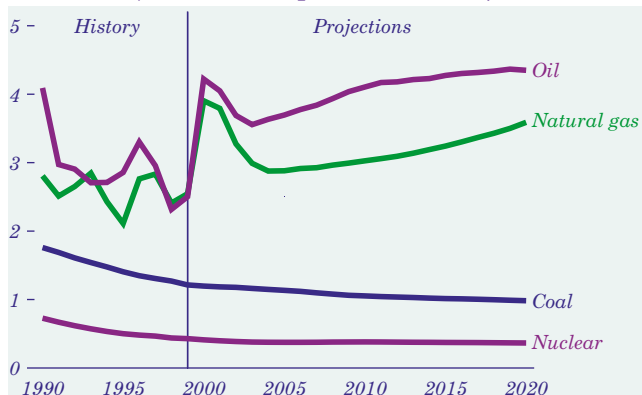
Before building new capacity, utilities are expected to use other options to meet demand growth—maintenance of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, assuming an average plant capacity of 300 megawatts, 1,310 new plants with a total of 393 gigawatts of capacity (excluding cogenerators) are projected to be needed by 2020 to meet growing demand and to offset retirements. Of this new capacity, 92 percent is projected to be combined-cycle or combustion turbine technology, including distributed generation capacity, fueled by natural gas (Figure 73). Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

Nearly 22 gigawatts of new coal-fired capacity is projected to come on line between 1999 and 2020, accounting for almost 6 percent of all the capacity expansion expected. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems have compelled vendors to standardize designs for coal-fired plants in efforts to reduce capital and operating costs in order to maintain a share of the market. Renewable technologies account for 2 percent of expected capacity expansion by 2020—primarily wind, biomass gasification, and municipal solid waste units. Nearly 13 gigawatts of distributed generation capacity is projected to be added by 2020, as well as a small amount (less than 1 gigawatt) of fuel cell capacity. Oil-fired steam plants, with higher fuel costs and lower efficiencies, are expected to account for very little of the new capacity in the forecast.

## Electricity Prices

### Rising Natural Gas Prices, Falling Coal Prices Are Projected

**Figure 74. Fuel prices to electricity generators, 1990-2020 (1999 dollars per million Btu)**

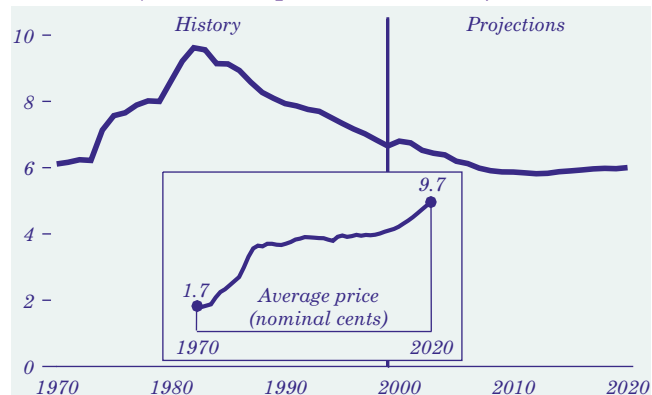


The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. In 1999, fuel costs typically represented \$25 million annually—or 79 percent of the total operational costs (fuel and variable operating and maintenance)—for a 300-megawatt coal-fired plant, and \$40 million annually—or 98 percent of the total operational costs—for a gas-fired combined-cycle plant of the same size. For nuclear plants, fuel costs are typically a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power plants than for fossil plants.

Over the projection period, the impact of rising gas prices is expected to be more than offset by the combination of falling coal prices and stable nuclear fuel costs. Natural gas prices to electricity suppliers are projected to rise by 1.6 percent per year in the forecast, from \$2.59 per thousand cubic feet in 1999 to \$3.66 in 2020 (Figure 74). The projected increases are offset by forecasts of declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around \$0.40 per million Btu (roughly 4 mills per kilowatthour) through 2020. Oil prices to utilities are expected to increase by 2.7 percent per year, leading to a decline in oil-fired generation of 81 percent (excluding cogeneration) between 1999 and 2020. Oil currently accounts for only 3.0 percent of total generation, however, and that share is expected to decline to 0.4 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

### Average U.S. Electricity Prices Are Expected To Decline

**Figure 75. Average U.S. retail electricity prices, 1970-2020 (1999 cents per kilowatthour)**



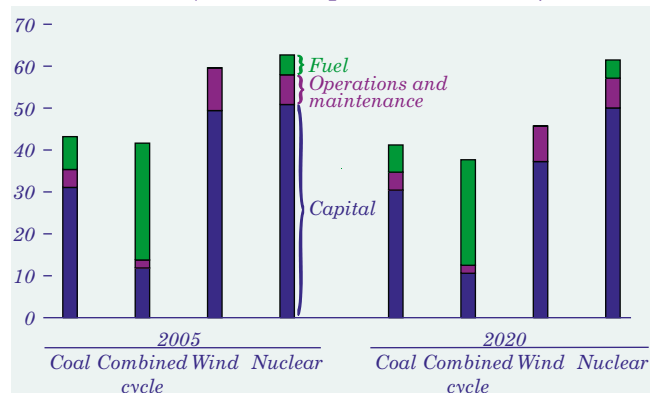
Between 1999 and 2020, the average price of electricity in real 1999 dollars is projected to decline by an average of 0.5 percent per year as a result of competition among electricity suppliers (Figure 75). By sector, projected prices in 2020 are 6, 16, and 11 percent lower than 1999 prices for residential, commercial, and industrial customers, respectively.

The reference case assumes a transition to competitive pricing in five regions—California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey and Maryland), and Texas. In addition, prices in the Rocky Mountain Power Area/Arizona, the Mid-America Interconnected Network (consisting of Illinois and parts of Wisconsin and Missouri), the Southwest Power Pool, and the East Central Area Reliability Council are treated as partially competitive, because some of the States in those regions have begun to deregulate their markets.

Specific restructuring plans differ from State to State and utility to utility, but most call for a transition period during which customer access will be phased in. The transition period reflects the time needed for the establishment of competitive market institutions and the recovery of stranded costs as permitted by regulators. It is assumed that competition will be phased in over 10 years, starting from the inception of restructuring in each region. In all the competitively priced regions, the generation price is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

## Least Expensive Technology Options Are Likely Choices for New Capacity

**Figure 76. Projected electricity generation costs, 2005 and 2020 (1999 mills per kilowatthour)**



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 76). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the competitive risk of siting new units.

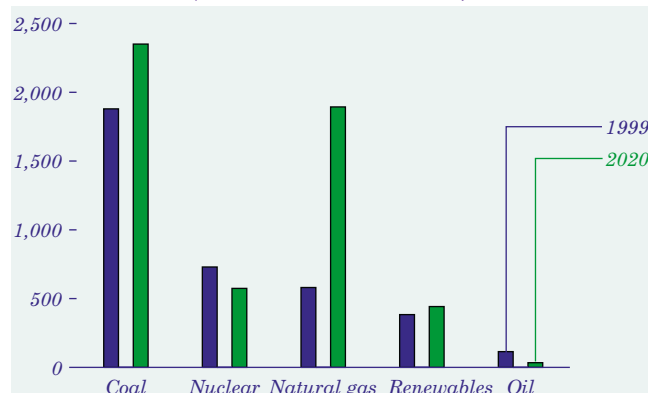
In the *AEO2001* projections, the costs and performance characteristics for new plants are expected to improve over time, at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates declining by 4 to 14 percent between 1999 and 2010, depending on the technology (Table 13).

**Table 13. Costs of producing electricity from new plants, 2005 and 2020**

Item	2005		2020	
	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
<i>1999 mills per kilowatthour</i>				
Capital	31.08	11.87	30.44	10.60
O&M	4.28	1.90	4.28	1.90
Fuel	7.84	27.86	6.49	25.18
<b>Total</b>	<b>43.20</b>	<b>41.63</b>	<b>41.22</b>	<b>37.68</b>
<i>Btu per kilowatthour</i>				
Heat rate	9,253	6,639	9,087	6,350

## Gas- and Coal-Fired Generation Grows as Nuclear Plants Are Retired

**Figure 77. Projected electricity generation by fuel, 1999 and 2020 (billion kilowatthours)**



As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2020 (Figure 77). In 1999, coal accounted for 1,880 billion kilowatthours or 51 percent of total generation. Although coal-fired generation is projected to increase to 2,350 billion kilowatthours in 2020, increasing gas-fired generation is expected to reduce coal's share to 44 percent. Concerns about the environmental impacts of coal plants, their relatively long construction lead times, and the availability of economical natural gas make it unlikely that many new coal plants will be built before about 2005. Nevertheless, slow growth in other generating capacity, the huge investment in existing plants, and increasing utilization of those plants are expected to keep coal in its dominant position. By 2020, it is projected that 11 gigawatts of coal-fired capacity will be retrofitted with scrubbers to meet the requirements of the Clean Air Act Amendments of 1990 (CAAA90).

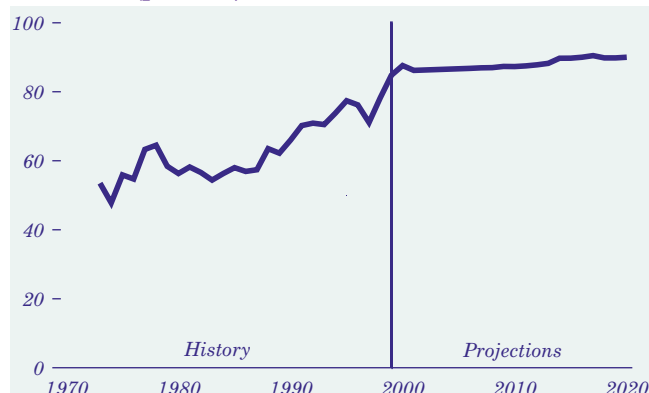
The large investment in existing plants is expected to make nuclear power a growing source of electricity at least through 2000. With substantial recent improvements in the performance of nuclear power plants, nuclear generation is projected to increase until 2000, then decline as older units are retired.

In percentage terms, gas-fired generation is projected to show the largest increase, from 16 percent of the 1999 total to 36 percent in 2020. As a result, by 2004, natural gas is expected to overtake nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants is projected to remain fairly small throughout the forecast.

## Nuclear Power

### Nuclear Power Plant Operating Performance Is Expected To Improve

**Figure 78. Nuclear power plant capacity factors, 1973-2020 (percent)**

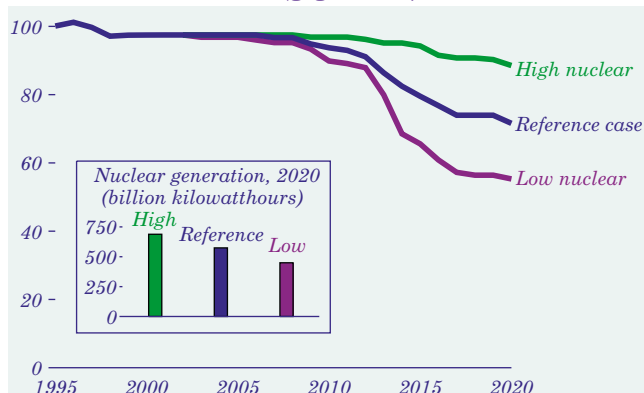


The United States currently has 104 operable nuclear units, which provided 20 percent of total electricity generation in 1999. The performance of U.S. nuclear units has improved in recent years, to a national average capacity factor of 85 percent in 1999 (Figure 78). It is assumed that performance improvements will continue, to an expected average capacity factor of 90 percent by 2015. In the reference case, 27 percent of current nuclear capacity is projected to be taken out of service by 2020, primarily as a result of operating license expirations. No new nuclear units are expected to become operable by 2020, because natural gas and coal-fired plants are projected to be more economical.

Nuclear units are projected to be retired when their operation is no longer economical relative to the cost of building replacement capacity. As a result, their operational lifetimes could be either shorter or longer than their current operating licenses. In the reference case, only one nuclear unit is projected to be retired before its current license expires, while 27 are projected to continue operating after their original 40-year licenses expire. In 2000, license renewals for two nuclear plants have been approved by the U.S. Nuclear Regulatory Commission. Three other applications are currently under review. As many as 17 other owners of nuclear power plants have announced intentions to apply for license renewals over the next 5 years, indicating a strong interest in maintaining the existing stock of nuclear plants. In addition, a nuclear industry task force has been developed to determine the key factors needed to prompt new orders of nuclear plants in the changing electricity market [86].

### Nuclear Power Could Be Key to Reducing Carbon Dioxide Emissions

**Figure 79. Projected operable nuclear capacity in three cases, 1995-2020 (gigawatts)**

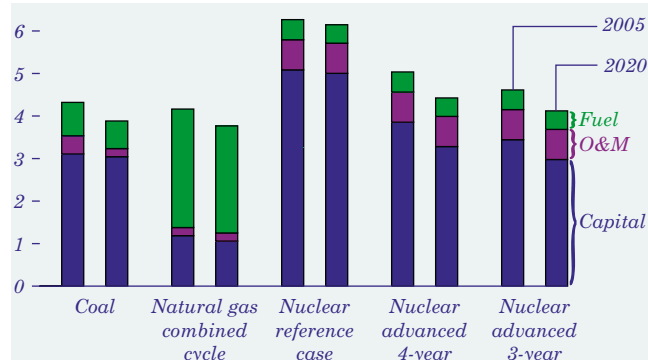


Two alternative cases—the high and low nuclear cases—show how nuclear plant retirement decisions affect the projections for capacity (Figure 79). In the high nuclear case, which assumes that the capital expenditures required after 40 years will be lower than in the reference case, more license renewals are projected to be obtained by 2020. Conditions favoring license renewal could include performance improvements, a solution to the waste disposal problem, and stricter limits on emissions from fossil-fired generating facilities. The low nuclear case assumes that the capital expenditures required for continued operation are higher than assumed in the reference case, leading to the projected retirements of 18 additional units by 2020. Higher costs could result from more severe degradation of the units or from waste disposal problems.

In the high nuclear case it is projected that 14 gigawatts of new fossil-fired capacity would not be needed, as compared with the reference case, and carbon dioxide emissions are projected to be 16 million metric tons carbon equivalent (2 percent of total emissions by electricity generators) lower in 2020 than projected in the reference case. In the low nuclear case, nearly 60 new fossil-fired units (assuming an average size of 300 megawatts) are projected to be built to replace additional retiring nuclear units beyond those projected to be retired in the reference case. The additional new capacity is projected to be made up predominantly of gas-fired combined-cycle units (72 percent) and combustion turbines (24 percent). The additional fossil-fueled capacity is projected to increase carbon dioxide emissions in 2020 by 2 percent above the reference case projection.

## Sensitivity Cases Look at Possible Reductions in Nuclear Power Costs

**Figure 80. Projected electricity generation costs by fuel type in two advanced nuclear cost cases, 2005 and 2020 (1999 cents per kilowatthour)**

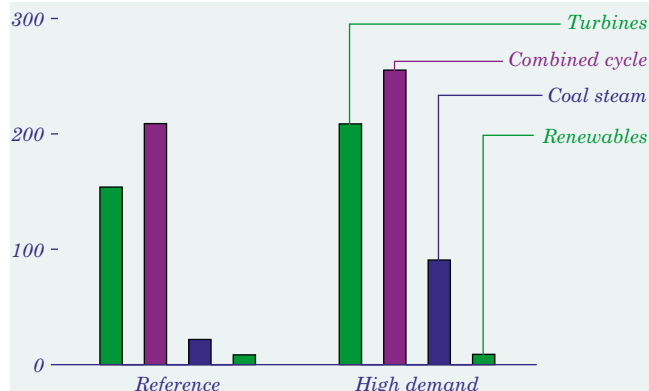


The *AEO2001* reference case assumptions for the cost and performance characteristics of new technologies are based on current estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. For nuclear power plants, a pair of advanced nuclear cost cases were used to analyze the sensitivity of the projections to lower costs and construction times for new plants. The cost assumptions for the two cases were consistent with goals endorsed by DOE's Office of Nuclear Energy, including progressively lower overnight construction costs—by 25 percent initially compared with the reference case and by 33 percent in 2020—and shorter lead times. The cost assumptions were based on the technology represented by the Westinghouse AP600 advanced passive reactor design. One case assumed a 4-year construction time, as in the reference case, and the other a 3-year lead time, the goal of the Office of Nuclear Energy. Cost and performance characteristics for all other technologies were as assumed in the reference case.

Projected nuclear generating costs in the two sensitivity cases are lower than in the reference case in 2005 and 2020 (Figure 80). A larger reduction is projected when a 3-year construction time is assumed to reduce financing costs, and nuclear generating costs in that case are projected to approach those for new coal- and gas-fired units. One new 460-megawatt advanced nuclear unit is projected to come on line in 2020 in the most optimistic nuclear cost case. The projections in Figure 80 are average generating costs; the costs and relative competitiveness of the generating technologies could vary across regions.

## High Demand Assumption Leads to Higher Fuel Prices for Generators

**Figure 81. Projected cumulative new generating capacity by type in two cases, 1999-2020 (gigawatts)**



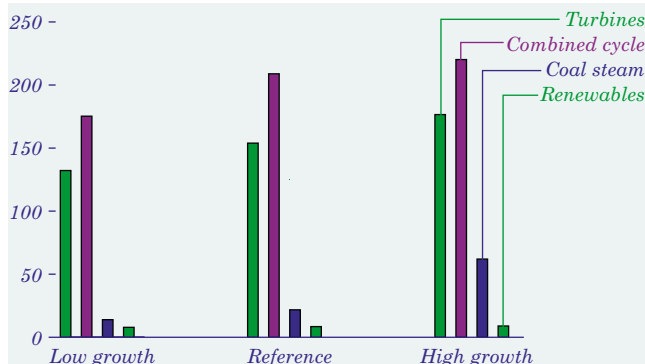
Electricity consumption grows in the forecast, but the projected rate of increase is less than historical levels as a result of assumptions about improvements in end-use efficiency, demand-side management programs, and population and economic growth. Different assumptions result in substantial changes in the projections. In a high demand case, electricity demand is assumed to grow by 2.5 percent per year between 1999 and 2020, as compared with the growth rate of 2.2 percent per year between 1990 and 1998. In the reference case, electricity demand is projected to grow by 1.8 percent per year.

In the high demand case, an additional 171 gigawatts of new generating capacity—equivalent to 569 new 300-megawatt generating plants—is projected to be built between 1999 and 2020 as compared with the reference case (Figure 81). The shares of coal- and gas-fired (including non-coal steam, combustion turbine, combined cycle, distributed generation, and fuel cell) capacity additions are projected to change from 6 percent and 92 percent, respectively, in the reference case to 16 percent and 82 percent in the high demand case. Relative to the reference case, there is a 17-percent increase in projected coal consumption and a 9-percent increase in natural gas consumption in the high demand case, and carbon dioxide emissions are projected to be higher by 123 million metric tons carbon equivalent (16 percent). More rapid assumed growth in electricity demand also leads to higher projected prices in 2020—6.4 cents per kilowatthour in the high demand case, compared with 6.0 cents in the reference case. Higher projected fuel prices, especially for natural gas, are the primary reason for the difference.

## Electricity: Alternative Cases

### Rapid Economic Growth Would Boost Advanced Coal-Fired Capacity

*Figure 82. Projected cumulative new generating capacity by technology type in three economic growth cases, 1999-2020 (gigawatts)*



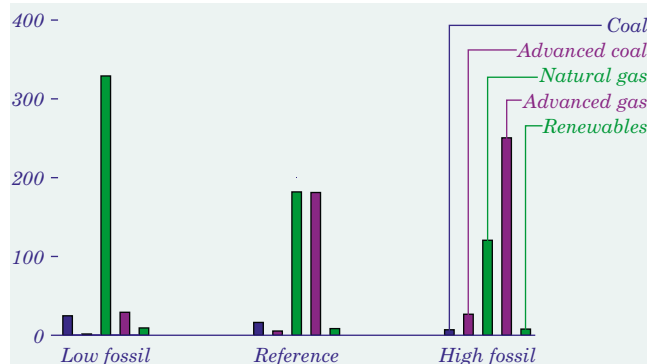
The projected annual average growth rate for GDP from 1999 to 2020 ranges from 3.5 percent in the high economic growth case to 2.5 percent in the low economic growth case. The difference leads to a 14-percent change in projected electricity demand in 2020, with a corresponding difference of 138 gigawatts (excluding cogenerators) in the amount of new capacity projected to be built in the high and low economic growth cases. Utilities are expected to retire about 9 percent of their current generating capacity (equivalent to 231 300-megawatt generating plants) by 2020 as the result of increased operating costs for aging plants.

Much of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new advanced coal-fired plants, which make up 50 percent of the projected new capacity in the high growth case. The stronger assumed growth also is projected to stimulate additions of gas-fired plants, accounting for 45 percent of the projected capacity increase in the high economic growth case over that projected in the reference case (Figure 82).

Current construction costs for a typical plant range from \$450 per kilowatt for combined-cycle technologies to \$1,100 per kilowatt for coal-steam technologies. Those costs, along with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option in some cases. Between 1999 and 2020, utilities are expected to maintain most of their older coal-fired plants while retiring many of their older, higher cost oil- and gas-fired generating plants.

### Gas-Fired Technologies Lead New Additions of Generating Capacity

*Figure 83. Projected cumulative new generating capacity by technology type in three fossil fuel technology cases, 1999-2020 (gigawatts)*

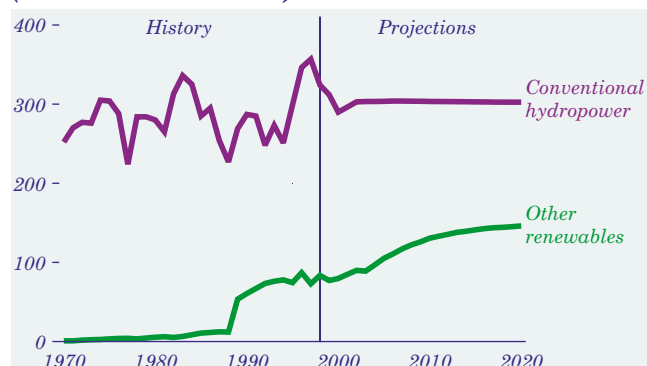


The *AEO2001* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs and/or heat rates for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, advanced combustion turbine, and molten carbonate fuel cell) were revised to reflect potential improvements in costs and efficiencies as a result of accelerated research and development. The low fossil fuel case assumes that capital costs and heat rates for advanced technologies will remain flat throughout the forecast.

The basic story is the same in each of the three cases—gas technologies are projected to dominate new generating capacity additions (Figure 83). Across the cases the projected share of additions accounted for by gas technologies varies only from 90 percent to 92 percent, but the projected mix between current and advanced gas technologies varies more significantly across the cases. In the low fossil fuel case only 8 percent (29 gigawatts) of the gas plants projected to be added are advanced technology facilities, as compared with a projected 68-percent share (251 gigawatts) in the high fossil fuel case. The projection for additions of coal-fired capacity is somewhat higher in the high fossil fuel case, whereas the projections for additions of new renewable plants do not vary significantly across the cases.

## Small Increases Are Expected for Renewable Electricity Generation

**Figure 84. Grid-connected electricity generation from renewable energy sources, 1970-2020 (billion kilowatthours)**

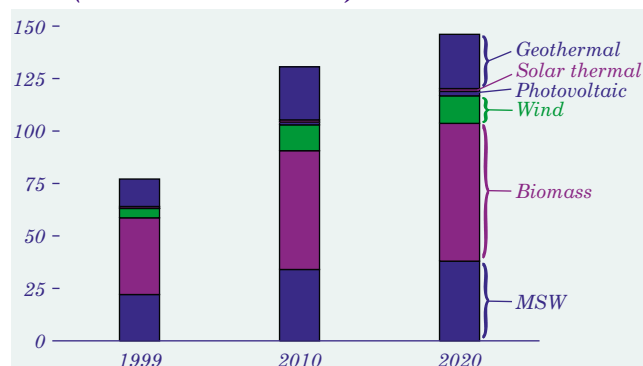


In the *AEO2001* reference case, projections are mixed for renewables in central station grid-connected U.S. electricity supply. Federal and State incentives are projected to produce substantial near-term growth for some renewable energy technologies, but generally higher projected costs are a disadvantage for renewables relative to fossil-fueled technologies over the forecast period as a whole. Total U.S. grid-connected electricity generation from renewable energy sources is projected to increase from 389 billion kilowatthours in 1999 to 448 billion kilowatthours in 2020, and generation from renewables other than hydroelectricity is projected to increase from 77 billion kilowatthours to 146 billion kilowatthours (Figure 84). Overall, renewables are projected to make up a smaller share of U.S. electricity generation, declining from 10.5 percent in 1999 to 8.5 percent in 2020.

Conventional hydroelectricity, which in 1999 provided 80 percent of the electricity supply from renewables, is projected to decline slightly in the forecast. The expected net addition of 600 megawatts of new hydropower capacity does not offset the projected decline in generation from existing hydroelectric facilities, as increasing environmental and other competing needs reduce their average productivity. Hydroelectric generation is projected to slip from 8.4 percent of the U.S. total in 1999 to 5.7 percent in 2020. The economic value of hydroelectric capacity is also likely to decline as environmental and other preferences shift generation to off-peak hours and seasons.

## Biomass and Landfill Gas Lead Renewable Fuel Use for Electricity

**Figure 85. Projected nonhydroelectric renewable electricity generation by energy source, 2010 and 2020 (billion kilowatthours)**



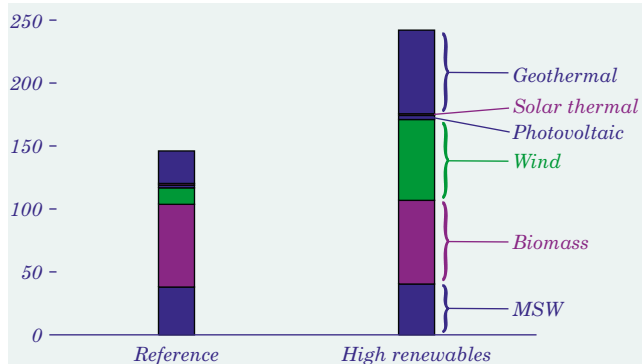
Most of the projected growth in renewable electricity generation is expected from biomass, landfill gas, geothermal energy, and wind power (Figure 85). The largest increase is projected for biomass, from 36.6 billion kilowatthours in 1999 to 65.7 billion in 2020. Cogeneration accounts for more than one-half of the expected growth in biomass generation; dedicated biomass plants and co-firing in coal plants account for the remainder. Electricity generation from municipal solid waste, including both direct firing with solid waste and the use of landfill gas, is projected to increase by 15.9 billion kilowatthours from 1999 to 2020. No new capacity additions are projected for plants that burn solid waste, but landfill gas capacity is projected to grow by 2.1 gigawatts.

Geothermal energy capacity is projected to increase by 1.5 gigawatts in the forecast, adding 12.8 billion kilowatthours of baseload generation by 2020. Intermittent generation from wind power is expected to increase in the near term as a result of the extension of the Federal production tax credit through 2001 (at 1.7 cents per kilowatthour) and by additional State incentives. Total wind capacity is projected to grow by 36 percent by 2001 and to more than double by 2010, but capacity additions are expected to slow after 2010 without additional incentives. High capital costs, lower output per kilowatt, and intermittent availability are expected to continue to disadvantage wind power relative to conventional generating technologies. Grid-connected photovoltaics are projected to add nearly 900 megawatts but remain small contributors to overall electric power supply. Off-grid photovoltaics, which are not included in the projections, are expected to continue to increase rapidly.

## Electricity from Renewable Sources

### Wind Energy Use Could Gain Most From Cost Reductions

**Figure 86. Projected nonhydroelectric renewable electricity generation by energy source in two cases, 2020 (billion kilowatthours)**

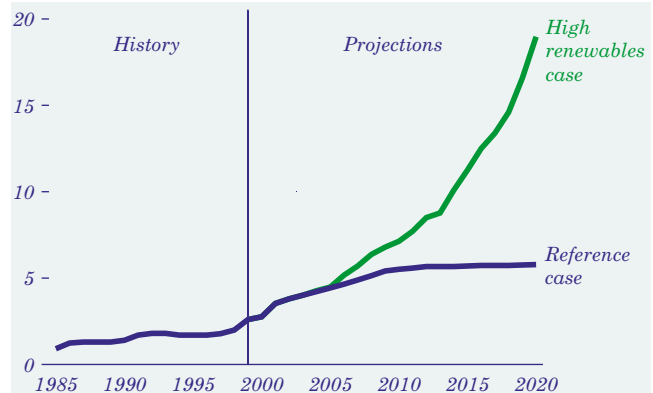


The high renewables case assumes more favorable characteristics for nonhydroelectric renewable energy technologies than in the reference case, including a 24-percent average reduction in capital costs by 2020 relative to the reference case, lower operations and maintenance costs, increased biomass fuel supplies, and higher capacity factors for solar and wind power plants. The assumptions in the high renewables case approximate the renewable energy technology goals of the U.S. Department of Energy. Fossil and nuclear technology assumptions are not changed from those in the reference case.

More rapid technology improvements are projected to increase renewable energy use, but the overall lead of fossil-fueled technologies in U.S. electricity supply is not expected to change. Total generation from nonhydroelectric renewables is projected to reach 242 billion kilowatthours in 2020, compared with 146 billion in the reference case (Figure 86), increasing from 2.8 percent of total generation to 4.6 percent. About 51 billion kilowatthours of the projected difference is from 13.2 gigawatts of additional intermittent wind capacity (Figure 87) and 41 billion kilowatthours is from 5.2 gigawatts of additional baseload geothermal capacity. Solar central station technologies are projected to remain too expensive, but small-scale photovoltaics are expected to grow more rapidly. The projected increase in renewable energy use in the high renewables case reduces fossil fuel use relative to the reference case projection, lowering projected carbon dioxide emissions by 14 million metric tons carbon equivalent (1.8 percent). Retail electricity prices are not projected to change significantly from the reference case.

### State Mandates Call for More Generation From Renewable Energy

**Figure 87. Wind-powered electricity generating capacity in two cases, 1985-2020 (gigawatts)**



*AEO2001* assumes rapidly increasing State requirements for investments in renewable energy technologies. The requirements, reflecting both energy and environmental interests, ensure investment in renewables despite increasingly competitive electricity markets. Renewable portfolio standards, which require increasing percentages of electricity supplies from renewables, are the most common, although other mandates also exist. Requirements differ from State to State, reflecting varying renewable resources, supporting industries, and supply alternatives. In *AEO98*, no quantifiable State mandates existed. *AEO99* projected 2,010 megawatts of renewable capacity additions as a result of State mandates through 2020.

The implementation plans for most State renewable energy mandates are uncertain, and it is difficult to project their effects on new capacity additions in some States. For *AEO2001* it is assumed that State mandates will require total additions of 5,065 megawatts of central station renewable generating capacity from 2000 through 2020, including 4,377 megawatts as a result of renewable portfolio standards. Mandated additions are expected to include 2,900 megawatts of wind capacity, 1,145 megawatts of landfill gas capacity, 840 megawatts of biomass capacity, 117 megawatts of geothermal capacity, and 64 megawatts of central station solar (photovoltaic and thermal) capacity—averaging a few hundred megawatts of total new renewable capacity in each year through 2012. After 2012, the current State mandates are estimated by EIA to result in about 330 megawatts of new renewable capacity additions.